ELECTRIC POWER RESEARCH INSTITUTE

Turbine-Generator Topics for Power Plant Engineers

Converting a Synchronous Generator for Operation as a Synchronous Condenser

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Technical Update, March 2014

EPRI Project Manager

J. Stein

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

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THE FOLLOWING ORGANIZATIONS, UNDER CONTRACT TO EPRI, PREPARED THIS REPORT:

JR Michalec Consulting

Southern California Edison

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The following organizations, under contract to the Electric Power Research Institute (EPRI), prepared this report:

JR Michalec Consulting
8088 Rookery Way
Westerville, OH 43082-8296

Principal Investigator
J. Michalec

Southern California Edison
2244 Walnut Grove Ave.
Rosemead, CA 91770

Principal Investigator
T.D. Duree

This report describes research sponsored by EPRI. Contributions from:

Jan Stein	EPRI
Kelly B. Simmons	Xcel PSCo
Gary M. Heimberger	Xcel Energy
Edward J. Baznik	FirstEnergy
James Fogarty	General Electric
Joe Hurley	Siemens
Edward J. Wingard	American Electric Power
Tedi Domowicz Duree	Southern California Edison

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ABSTRACT

Reactive load is constantly varying with transmission system load. Transformers and inductor motors draw current, which in turn causes voltage lag and impacts the transmission system as a whole. A synchronous condenser (SC) can compensate for system reactive changes and maintain the required system voltage set point by varying excitation or magnetic field strength of the SC's field winding, thus generating or absorbing reactive power. The SC can offset some of the reactive power changes required by inductive or capacitive system loads. Significant SC benefits include the fact that an SC produces no switching transients, remains unaffected by system electrical harmonics, and does not produce harmonics on the transmission grid.

This report highlights the technical issues associated with converting an existing shutdown or retired synchronous generator to operation as an SC. Beginning with the basic conversion process, the report documents the type of changes needed for major equipment components, suggested maintenance, and the expected reactive capability to be made available. Other issues discussed include controls that must be retained or added; required unit protection; unit interface to the grid, transformers, and other generation-related equipment; experience with utility SC conversions and other known conversion projects; cost of SC conversion; and various North American Electric Reliability Corporation (NERC) and regulatory issues. The intent of this report is to point out issues that must be addressed in order to achieve successful conversion of a synchronous generator to an SC, not to focus on one particular conversion scenario.

Keywords

Synchronous condenser
Synchronous generator
Synchronous generator conversion issues
Voltage lag
Transmission system
Reactive load
Reactive power

DEFINITIONS, ABBREVIATIONS, AND UNITS

Owner	The entity that owns the generator
Operator	The Owner or another party if the work is contracted out.
Unit	The turbine-generator and auxiliaries to be converted
Start-up Drive	The means of driving the condenser to the required speed for successful and routine synchronizing to the System
System or Grid	The transmission circuit synchronized to the condenser
AEP	American Electric Power
OEM	Original Equipment Manufacturer
IEEE	Institute of Electrical and Electronic Engineers
SG	synchronous generator
SC	synchronous converter
AFD	adjustable frequency drive
NERC	North American Electric Reliability Corporation
PRC	NERC - Protection and Control (Standards Family)
MOD	NERC - Modeling, Data, and Analysis (Standards Family)
VAR	NERC - Voltage and Reactive (Standards Family)
CRO	control room operator
SVC	static-var compensation
STATCOM	static synchronous compensator

The following abbreviations are per IEEE Std. 280-1985 (R1997) Standard Letter Symbols:

MVA	mega volt ampere
MW	mega watt
kV	kilo volt
var	volt ampere reactive
Mvar	mega var
Hz	Hertz, cycles per second
HP	horsepower

FOREWORD

Southern California Edison is looking to provide a learning resource for others, and to have it serve as a springboard to further investigation. The aim is to disseminate technical issues encountered during a basic conversion of a synchronous generator to a synchronous condenser, while attempting to harness the benefits in re-use of an existing asset.

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1 INTRODUCTION

This is intended as an elementary document.

This document will start out as a basic level text, much like a freshman college course, “Generator to Condenser 101.” This procedure cannot detail every step required for a successful conversion. It is hoped that when engineers responsible for assessing electrical equipment, mechanical equipment, controls, protection, excitation, maintenance, operation, and transmission issues read this, they will say “We can do that!”

For context, the Author was a generator engineer at American Electric Power (AEP) for the successful conversion described in Appendix A and the unused conversion in Appendix B. The design and execution of these projects were done in-house, there was little involvement from the generator Original Equipment Manufacturer (OEM); however, when we asked a few questions, they did respond.

1.1 Purpose

The purpose of this document is to: a) identify the technical issues related to conversion of an existing steam turbine driven generator for operation as a synchronous condenser; b) perform a literature search on previous conversions, primarily thru the Institute of Electrical and Electronic Engineers (IEEE) system and contacts with industry colleagues, and c) collect lessons learned from past conversions, where available.

1.2 Scope

This document will highlight the technical issues associated with converting an existing shut-down or retired synchronous generator to operation as a synchronous condenser. Categorizing it as “retired” is a foundation criteria point because if the conversion would later need to be reversed, then it has impact on which equipment components need to be retained.

It will start from the basic conversion process, including what changes are needed for major equipment components; which are required for condenser operation; suggested maintenance for the condenser operation; and the expected reactive capability to be made available. Other issues addressed include controls required to be retained or added, protection for the unit as well as its interface to the grid, transformers, and other generation related equipment.

The intent is to be able to apply this procedure to various conversion scenarios. Since a specific project is not identified, many details of the conversion process are not known. The idea is that, once a specific Unit has been selected for conversion, this document will be beneficial to the engineers by pointing out the issues necessary to achieve a successful conversion.

The generic basis of this document is:

- The decision has been made to perform the conversion.
- Both the Generating Co. and the Transmission Co. were involved in the decision.

- The retired turbine generator remains in place at the generating plant.
- The subject Unit is a 2-pole or 4-pole synchronous generator.
- The generator is cooled by air, hydrogen, or hydrogen and water.
- All of the original generation equipment associated with the Unit and the auxiliaries are still in place and serviceable.
- The generator high voltage leads, the generator step-up transformer, all high voltage breakers are in place and serviceable.
- Since retiring, the Unit's equipment has been stored and maintained in serviceable condition.
- The generator rotor will not need to be removed for inspection.
- The Unit will not be returned to service as a Generation Asset.
- The Unit is intended to operate as a condenser for several years.
- It is assumed that the Engineering and Personnel of the Owner of the Unit will be undertaking the bulk of this activity, or the Operator, on behalf of the Owner.
- The OEM will be asked for input as required.
- Of course, the conversion could be a turnkey contract to a Vendor.
- Some of the major economic factors will be identified in this paper.

Hydro synchronous generators are not covered here; however, they can also be converted for condenser operation, especially if the unit was a pump storage motor/generator. The motor/generator is usually designed to start directly across-the-line with reduced voltage; it does not require a start-up drive. The hydraulic turbine could be uncoupled. Of course the location of the units thrust bearing may be an issue. Unfortunately, most hydro units are not physically close to a system load; they may not provide enough reactive support to be effective.

A few definitions may help:

Owner	The entity that owns the generator.
Operator	The Owner or another party if the work is contracted out.
Unit	The turbine-generator and auxiliaries to be converted.
Generator	The synchronous generator (SG) to be converted.
Condenser	The generator converted to a synchronous condenser (SC).
Start-up Drive	The means of driving the condenser to the required speed for successful and routine synchronizing to the System.
Adjustable Frequency Drive	Adjustable Frequency Drive (AFD) is a three phase adjustable frequency system used to bring the unit to rated speed as a synchronous motor; [a.k.a. VFD (variable frequency), ASD (adjustable speed), VSD (variable speed), SFC (static frequency converter), or an inverter drive].
System or Grid	The transmission circuit synchronized to the condenser.

2

THE SYNCHRONOUS CONDENSER

In today's Utility market, transmission system stability is a major concern. Many steam units are being shut-down and replaced by wind and solar generation which provides essentially no reactive load support to the System. Power electronics can be used to achieve the phase angle and reactive power that the System needs at the point of connection; however, the electronics often creates harmonics, a negative impact on the System.

Reactive load is constantly varying with system load. Transformers and inductor motors draw current lagging the voltage, which means such devices impact the System. The synchronous condenser (SC) can compensate for System reactive changes and maintain the required System voltage set point by varying excitation or the magnetic field strength of the condenser's field winding thus generating or absorbing reactive power. When converted, the synchronous condenser can offset some of the reactive power changes required by inductive or capacitive System loads. There is a significant benefit to the use of a synchronous condenser; the SC produces no switching transients; is not affected by system electrical harmonics; and does not produce harmonics on the Transmission Grid.

Figure 2-1 is a typical reactive capability curve for a 907 MVA, 816 MW, 0.9 power factor, 75 psig hydrogen and water cooled generator. The shaded area of the curve is where the synchronous generator will basically operate as a synchronous condenser (SC). Theoretically, this unit can operate with reactive power across the range from +700 Mvar to approximately -350 Mvar. This is meaningful since it represents a broad range where a synchronous condenser could be in a support mode of the usual and regularly occurring Grid variability.

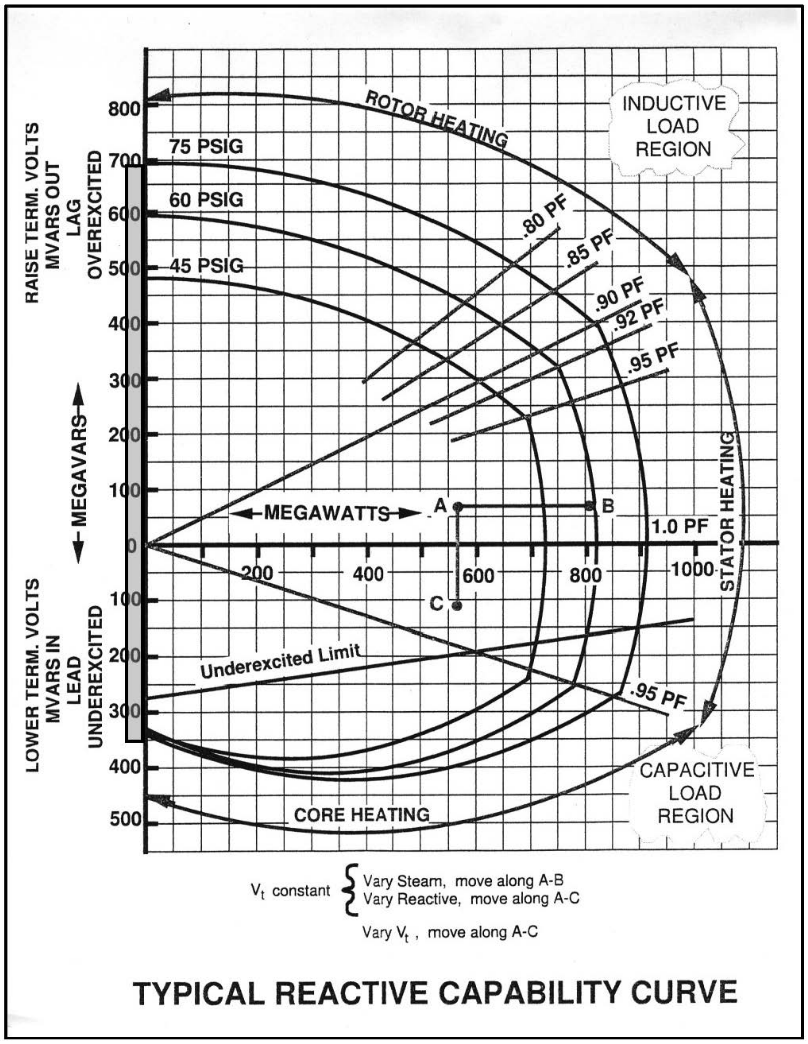

Figure 2-1
Typical Reactive Capability Curve (V_t is generator terminal voltage). The Shaded Box represents the range of synchronous condenser operation.

3
EXPECTED REACTIVE CAPABILITY AVAILABLE

3.1 The Reactive Capability Curve

The Reactive Capability Curve, Figure 2-1, shows the thermal capability of the synchronous generator to produce real power and reactive power. If the Transmission System demands operation of the generator beyond the specified thermal limit curves, the synchronous generator will over heat. Operation with positive Mvars means operation with an inductive load (lagging) providing reactive power, and operation with negative Mvars means operation with a capacitive load (leading) consuming reactive power. The shaded area in Figure 2-1 represents the reactive capability of the generator when converted to condenser operation. The area is shown on the left of the Mvar axis since, as a condenser, the Unit draws power from the system, acting as a synchronous motor, when operating as a synchronous condenser.

3.2 The Vee Curve

The Vee Curve, Figure 3-1, allows us to see across the air gap of the machine and shows the relationship between the stator loading and the excitation field current. In Figure 3-1, as a condenser, the operation will be along the lower limits of the Vee Curves, from A to B to C. The full range of field amperes is necessary to operate throughout this range. That means that, for this specific unit, the field winding will see field current from ~300 amps to ~5300 amps.

The Vee Curve shows the maximum lagging reactive load for this unit will typically require about 72% of full load stator current; this is point “C” on Figure 3-1. The maximum leading reactive load will require only about 36% of full load stator current; point “A”.

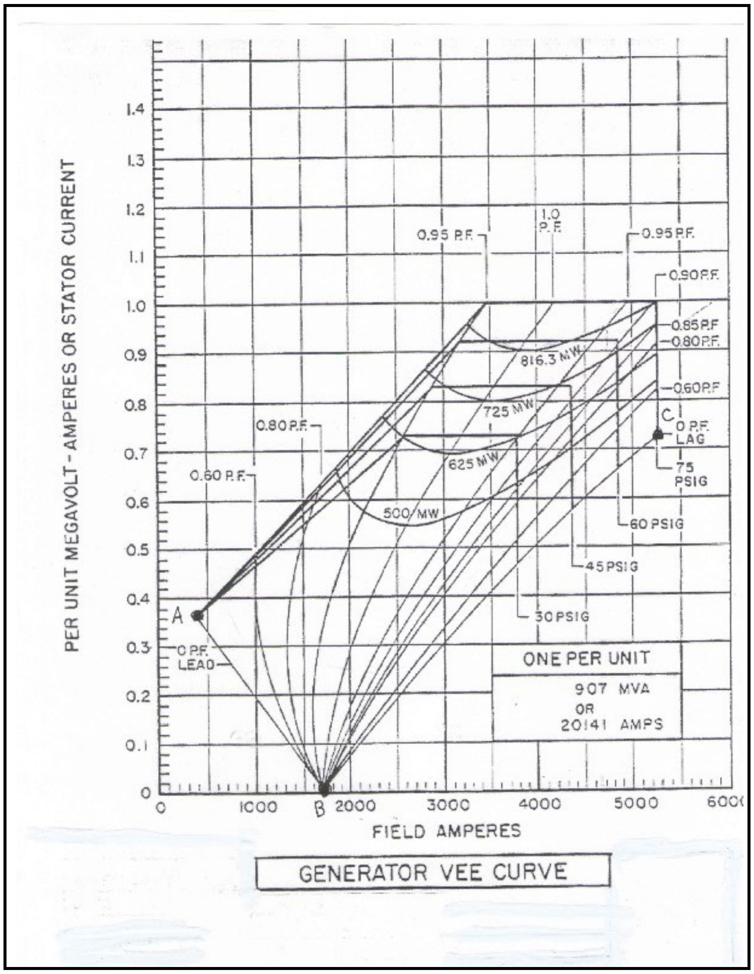

Figure 3-1
Typical Vee Curve

3.3 The SC's Operating Limitations

Basically, all of the operating limits required of the generator will be the same for a condenser. However, because of the condenser's reduced range of operation, those operating limits are less likely to be exceeded.

The major operating limitation of a synchronous generator is over current on the stator winding or the field winding and the resultant increased electromechanical forces on the windings and winding overheating. The temperature rise on the field winding as a condenser can be identical to operation at rated full load as a generator.

The effect of heating is a current squared (I^2R) function. In basic terms, operating the stator or field windings with an over current of 10% above rated current will result in over heating of 121%. On the other hand, when operating as a condenser at 70% of rated current, it will result in only 49% of the full load heating. This is a significant operational change since a condenser is more likely to operate at less than nameplate full load heating. Therefore, the temperature rise on the stator winding will be much less, while the temperature rise on the field winding can be nearly identical to the temperature rise as a generator.

The existing limitations associated with maintaining the Unit or Grid voltage will be unchanged. This parameter will be kept within range using the voltage regulator. If the voltage regulator is not equipped with over or under excited limiters, this protection will be needed for SC operation. (see Appendix A).

Limitations associated with the air, hydrogen, or stator cooling water (chemistry and conductivity), seal oil system, lubrication system, vibration, and the excitation system will basically be unchanged, since each of these components will be utilized in the new configuration.

It is likely that if the generating Unit had plant-specific reactive capability limits, those same limits would be there if the generator was converted to operation as a synchronous condenser.

The amount of reactive capability expected from a converted synchronous generator was discussed in Sections 3.1 and 3.2. Those familiar with the North American Reliability Corporation (NERC) requirements for verification of a synchronous generator's reactive capability know that often, the generator's full design capability, shown on the reactive capability curve, Figure 2-1, is often not actually available to the Transmission Grid due to issues with the plant's auxiliary bus voltage or equipment limitation. To demonstrate the unit's reactive capability limits requires increasing the field current to obtain the maximum lagging power factor and then lowering the field current to obtain the maximum leading power factor. This, of course, raises and lowers the generator's terminal voltage and therefore the plant's auxiliary bus voltage. Depending on a plethora of issues, these plant-specific limits can be high or low auxiliary bus voltage limit, volts per hertz limit, a field over current limit, a system stability limit, the Voltage Regulator's under excited limit, or the Grid voltage requirement at the time of the test. These limits may be reached before the design generator's (or condenser's) capability is exceeded.

4
THE BASIC CONVERSION PROCESS

4.1 An Overview

As noted in the purpose and scope, the focus of this work is to identify technical issues related to conducting a conversion. Thus, a basic conversion process is provided.

- Remove the turbine at the turbine-end of the generator.
- Replace that turbine with a Start-up Drive System capable of accelerating the condenser up to synchronizing speed.
- Install a bearing to accommodate the axial thrust developed by the condenser during startup and shut down.
- Evaluate and modify the turbine generator lube oil system since the turbine bearings may not be used.
- Evaluate and modify the generator auxiliaries, they will all be used.
- Accelerate the generator to just above synchronous speed.
- Energize the excitation system and synchronize the condenser to the Transmission System.
- De-energize, disconnect, or free wheel the Start-up Drive System while the Unit is on line.
- Use the existing Voltage Regulator Automatic Controls to maintain the desired System (condenser terminal) voltage.

4.2 Decisions Effecting the Conversion

There are a number of fairly straight forward questions that will help ascertain if a conversion is an appropriate use of this retired asset. Questions such as these might also help point out areas to address as part of the economic evaluation.

A. Has it been assessed whether the location of the power generating station is the appropriate location to significantly influence the System's reactive needs?

B. Are there plans to return the Unit to service as a Generating Asset?

C. How long is it intended for the converted Unit to operate as a condenser?

D. Does the stator or the rotor need to be rewound? If so, significant costs will be incurred. Depending on the Unit size, a stator rewind could be $3M to $10M and a rotor rewind $1M to $3M. Should an upgrade be considered? See Section 8.2.5 for additional considerations if a rotor rewind is necessary.

E. Will the conversion take place with the generator in place at its current location in the power generating station or will the generator be relocated?

F. What range of lagging and leading reactive load is anticipated?

G. How often will the SC be started and stopped?

H. Will the condenser be locally controlled or remote controlled? Remote control will add to the cost.

I. And finally, who will be the Owner; the Generating Company or the Transmission Company? This is important to the evaluation because there are costs associated with Operation which, if borne in-house, could keep the project from becoming cost-prohibitive. It might be deemed that a separate Operator is appropriate. Such considerations are outside the scope of this paper.

4.3 The Plant Equipment

Starting from the existing plant equipment, there are several components that will or will not be utilized in a conversion from synchronous generator to synchronous condenser, or that will need to be acquired, in order to complete the process. This section identifies which equipment falls under which category, and what criteria might determine whether they will be useful in the new configuration.

The existing equipment in the generating plant that <u>will not be used</u> in the conversion includes:

- anything associated with the steam generator, the boiler, or the fuel supply to the boiler
- air pollution control equipment
- the turbine (except for turbine lubrication, bearings, or turning gear)

Disposition of this not used equipment is outside the scope of this document.

The existing equipment in the generating plant that <u>will be used</u> in the conversion includes:

- the generator's step-up transformer with its auxiliaries, cooling, breakers, protection
- the high voltage connection between the generator and the step-up transformer, this will be either cable, non-segregated phase bus, segregated phase bus, or isolated phase bus
- if the high voltage bus had a cooling system it may or may not be required for operation as a condenser
- the generator itself
- the generator auxiliaries, cooling, (air, hydrogen, water) bearing lubrication
- raw water flow to the generator and auxiliaries
- the rotor shaft grounding system
- if the Unit had a turning gear assembly, it will be re-used
- the excitation system, Voltage Regulator, and controls
- the generator metering and protection circuits
- some turbine lubrication or turbine bearings (depending on the condenser Start-up Drive System)
- raw water flow to the bearing oil coolers may have to be modified
- the turbine turning gear assembly is often attached directly to the turbine shaft, the condenser will probably need this turning gear
- the plant's DC battery backup system will be required for the condenser and it's auxiliaries; this is required for safe shut-down; the battery capacity can probably be down sized by 50% or more

- the plant's fire protection should remain in service for the condenser and it's auxiliaries; this system can also be down sized to approximately 25%
- for retired plants, some plant heating may need to remain in service for the condenser and it's auxiliaries
- of course, the condenser plant facilities must be maintained and secured as an active site

The new equipment that may be needed could include:

- a condenser Start-up Drive System (perhaps the largest cost item)
- possibly a new turning gear assembly (if the existing one cannot be re-purposed)
- possibly a new Voltage Regulator, this depends on the control, protection, and limiter circuits of the existing Voltage Regulator, whether they can be adjusted for the new range of operation
- possibly new oil or water pumps for lubrication and cooling water (based on the plant's specific cooling water and lube oil piping system, and the possible re-sizing of the pumps)
- in some cases a stub shaft will need to be added if a new thrust bearing must be installed
- the condenser bearings may need to have a bearing oil-lift system installed
- possibly a new transformer fed potential source static excitation system depending on the generator-exciter configuration (another significant cost item, $1M+)

4.4 Condenser Operation and Maintenance

4.4.1 Operation

Now, here we could have another issue. Consider Section 4.2, question 9; "…..who will be the Owner; the Generating Company or the Transmission Company?" Of course, the Gen Co. will be intimately familiar with the equipment, its operation and maintenance. In today's electric Utility environment, with the separation of generation and transmission, this creates a problem since the Trans Co. engineers are definitely not familiar with this rotating equipment. A likely scenario is for the Trans Co to simply contract with the Gen Co to operate and maintain the synchronous condenser. Or, the Trans Co. may have to contract knowledgeable people to operate and maintain the condenser.

When the condenser is synchronized to the System, the Control Room Operator's (CRO) activities, associated with the condenser and its auxiliaries, are the same as they would be for a generator. Of course, most of the balance of plant equipment, required for generation, is not in use. The auxiliaries, the excitation system, the voltage regulator, the protection and control circuits, the high voltage bus, and the generator auxiliary and step-up transformers will all function the same when operating as a condenser. When a generating plant is no longer operating as such, these CRO activities would need to shift to the Grid operator. Or, this role would need to be retained at the plant. Such decisions required for re-alignment of ancillary tasks is outside the scope of this document.

4.4.2 Maintenance

Basically, the general maintenance required for a generator is the same required for condenser operation. Maintenance of the bearings; the lube oil; the hydrogen system; the stator cooling water; air cooling systems; the hydrogen seal oil system; and the excitation system will all be the same. The routine maintenance issues such as: the carbon brushes; cooling air filters; the occasion lubrication oil leak; or a hydrogen leak must be attended to. Vibration should not be an issue. Even off-line, the condenser will require little maintenance. Inspections, requiring rotor removal are often scheduled at 5 to 8 year intervals based on experience and industry practice.

As a generation asset, the goal was to be on-line at or near full load and stay there. Operation as a condenser may require more start/stop cycling. Frequent start/stop operation may increase maintenance for the condenser and Start-up Drive. The addition of the Start-up Drive will add more maintenance to the condenser; of course, this depends on the type of Start-up Drive used. Depending on the design and arrangement of the condenser's Start-up Drive System, there will be some additional maintenance associated with this equipment.

Operating as a condenser, the Unit and its auxiliaries will see no additional wear and tear. Due to the generally lower stator current and the resultant lower electromechanical forces and lower stator winding temperature rise, overall maintenance as a condenser will be less.

5
THE GENERATOR

5.1 Evaluation for Serviceability

In the Scope, the base assumption is that the generator and auxiliaries were taken out of service and maintained and stored in anticipation of returning to service someday. All of the generation equipment is available. Here are suggested activities and tests to determine the serviceability for conversion to operate as a condenser. If tests fall outside acceptable parameters, then a decision must be made, depending on economics and timing, whether to take corrective action. Costs for repairs may challenge the overall economic evaluation. See Section 14 on costs.

Review the Unit's operating history. Was the Unit properly maintained during its service life? Are there any known deficiencies that need to be addressed? Are all of the auxiliaries in serviceable condition?

Review the Unit's condition since it has been in storage. Is there anything that needs to be addressed?

Review the condition of the auxiliary equipment:

- Bearing lubrication system
- Air cooling issues, filters, and cleanliness of cooling ducts
- Hydrogen storage system
- Hydrogen coolers, cleanliness, leaks, pressure tests
- Stator cooling water system
- Excitation system, brushes, Voltage Regulator
- Generator and exciter bearings
- Generator high voltage bushings
- Generator bushing current transformers and potential transformers
- Generator high voltage bus condition
- Generator step-up transformer and the auxiliary transformers
- Generator and transformer high voltage breakers

Perhaps the most significant evaluation activity is a visual inspection of all the equipment involved in the conversion. A knowledgeable equipment specialist should perform these inspections. Do not perform any electrical testing until a through visual inspection has been completed on all of the equipment involved in the conversion. Keep in mind that if the stator or rotor requires a rewind, the rewind vendor should provide a statement that the machines electrical characteristics have not changed. If the unit is rewound and up-rerated, the Vendor must provide a list of the electrical characteristics that have been affected. NERC should be informed of any changes that will affect the Units performance when synchronized to the Transmission System. Reference Section 14.

Stator

The stator most likely will not need to be rewound. Remember, the stator winding will be operating at about 70% of rated load current and the forces on the windings will be less than 49% of the full load design forces. Disconnect the generator from the high voltage bus at or near the generator bushings and perform the following tests:

- Measure each phase resistance; readings should be within 5% of each other.
- Megger® each phase, use 5,000 volt DC, the insulation resistance (IR) readings should be several hundred Mohms.
- Calculate the Polarization Index, this should be 2.0 or better, a reading of 1.5 may be acceptable.
- If deemed necessary, perform an AC high potential test on each phase at 1.25 × rated terminal voltage for one minute. (Remember, this is a pass/fail test. If the winding fails, a full rewind may be needed.)
- For a water cooled stator winding, the cooling water system should be in service and operating at the design flow and conductivity. The insulation resistance will only be a few Mohms and a Polarization Index is meaningless. The water system should be checked for leaks.
- For a dry water cooled stator winding, the cooling water system will be out of service. Confirm that the system is "dry" with no standing water in the winding. The insulation resistance will be several hundred Mohms and a Polarization Index should be about 2.0 or better. The high potential test can be performed. If there is water inside one of the Teflon hoses, it could flash over during the test.

Rotor

The field most likely will not need to be rewound. Remove all of the carbon brushes from the collector ring assembly and remove all of the carbon dust build-up.

- If possible, perform a pole drop measurement.
- Megger® the field winding, use 500 to 1,000 volt DC, the insulation resistance should be several Mohms.
- Calculate the Polarization Index; a reading of 1.5 is acceptable for field windings. (Ref 1)
- Measure the winding resistance, correct for temperature, and compare this with past resistance readings.
- f deemed necessary, perform an AC high potential test at 1.25 × rated DC for one minute. (Remember, this is a pass/fail test. If the winding fails, a full rewind may be needed.)
- Evaluate the condition of the shaft grounding system, it will be needed. If this is on the turbine shaft it will have to be relocated to the generator shaft.
- Evaluate the condition of the collector rings, is there excessive wear.
- Evaluate the condition of the brush rigging and brush holders, are the holders clean and clear of burrs, do brushes move freely within the brush box?

Exciter

- The rotating exciter should be thoroughly inspected. Ideally, the rotor should be removed for the inspection and be thoroughly cleaned to remove the carbon dust build-up.
- Evaluate the condition of the commutators if a DC exciter is involved.
- Inspect the brush holders.
- Inspect the Voltage Regulator.
- Perform a Voltage Regulator functional check.
- Review the Voltage Regulator circuits; are they sufficient for condenser operation?

An estimated time for the above activity is:

- 3 to 4 days - Review the past history of maintenance and repair activity (1 or 2 station personnel)
- to 3 days - Visual inspection of all equipment (2 or 3 station personnel)
- 2 days - Remove generator access openings (2 or 3 station personnel)
- 5 to 7 days - If the generator rotor is removed for inspection
- 1 to 2 days - Inspect the stator and rotor; perform a wedge tightness check of the stator (1 or 2 generator engineers)
- 5 to 7 days - to re-install generator rotor (using required number of station personnel)
- 2 days - Electrical tests (2 or 3 station personnel)
- 2 days - Replace generator access openings (2 or 3 station personnel)

5.2 Generator vs Condenser Operation

This typical generator is designed to operate and withstand all of the forces associated with the normal voltage stress, current heating, electromagnetic forces, and centrifugal force at full load conditions.

As an example, consider the generator introduced in Section 2 rated at 907 MVA with:

Terminal Voltage	26 kV
Full load stator current	20,100 ac amps
Field voltage	675 VDC
Full load field amps	5300 DC amps
Frequency	60 Hz
Speed	3600 rpm

Operating as a condenser, the normal forces associated with voltage and shaft rotation are the same. The field windings will see basically the same voltage, current, and mechanical forces. However, stator winding current is less when operating as a synchronous condenser. So, the stator's heating and electromagnetic forces are much less. Heating in a generator or condenser stator winding is an I^2R function and the electromagnetic forces on the stator winding are also proportional to I^2.

Here is general information concerning the amount of stator current required, based on the generator full load rated current, to operate a generator as a synchronous motor at rated speed with the turbine coupled to the generator. (Ref. 2)

- a typical condensing turbine – up to 3%
- a typical non-condensing turbine – 3% to 10%
- a typical hydraulic turbine – 0.2% to 2.5%
- a typical gas-turbine – 10% to 50%
- a typical diesel engine – 15% to 25%

This generator motoring current is being used to overcome windage and friction losses and rotate the turbine, now acting as a fan.

When operating as a condenser, the load associated with the turbine has been removed. During starting, the condenser will then draw about 1% of the Unit's full load current. This very low stator current will result in a significant reduction of the heating and electromagnetic forces, well below 0.01% of those imposed on the stator winding at full load. During starting, the bushing current transformer circuit and the relaying and protection circuits should be reviewed for proper operation due to this low starting current.

The field winding DC current and DC voltage, during condenser starting, depends on the starting method. Regardless of the starting method, the field winding will not see abnormal conditions.

The overall losses will be less when operating as a synchronous condenser.

Stator I^2R losses:	about 50% less
Rotor I^2R losses:	basically the same as full load
Core losses:	the same
Windage and friction losses:	the same
Stray losses:	the same

5.3 All Auxiliaries Needed

All of the generator's auxiliary systems are needed for operation as a condenser.

Cooling

For air cooled Units: The cooling arrangements will remain the same, no changes are expected.

For hydrogen cooled Units: The cooling system will have to be used to remove heat from the core, field winding, stator winding, and losses from windage and friction. The hydrogen bulk supply system, hydrogen purity, low hydrogen moisture, and the seal oil system need to be maintained the same.

For water cooled Units: Many of the early water cooled units actually had capability, some up to 50% load, without water flow. If this is not possible, then the water cooling system needs to be retained. Water flow, pressure, chemistry, and conductivity have to be maintained. Remember, low conductivity is still required since the stator winding will operate at rated voltage. However, the amount of heat removed is reduced with condenser operation. Raw water flow to the stator water coolers may have to be reduced in order maintain and control stator cooling water temperature to avoid getting this stator water too cold. This is an area where the generator OEM may have to be consulted.

Hydrogen Seal Oil

For hydrogen cooled Units, the seal oil system must remain in service; no changes are expected.

Bearings

In general, the Unit's bearings should not require any changes. However, depending on the design of the Start-up Drive System, bearing lubrication may need to be evaluated for extended operation at low speeds during start-up. In some applications, startup could take up to 20 minutes. The OEM should be contacted for the effects of low speed operation on the bearings. If the generator bearings have an oil-lift system it should be used. There is a possibility that on some units without a bearing oil-lift system, that an oil-lift system may be required to reduce the starting torque.

By design, synchronous generators do not have thrust bearings. Any thrust load from the generator or turbine is contained by the turbine thrust bearing. As we know, a synchronous generator may develop some axial thrust during start-up and shut down. This axial thrust is due to several reasons. Depending on the design of the cooling gas flow, the cooling fan or blower arrangement may actually create rotor thrust. If the blower is only on one end of the rotor and forces gas flow all the way to the other end it will likely produce axial motion. If there are fans on both ends of the rotor, they may not produce a well-balanced gas flow and could produce axial thrust. On units with different size bearings there is a tendency for the gas flow to produce a force toward the larger bearing, typically on the turbine-end. During shutdown, the not so symmetrical, decay of the stator and rotor flux may cause the field to move axially.

Once at speed and synchronized to the System, the generator will operate in the magnetic center of the stator field and not develop any thrust.

The axial thrust developed by a large synchronous generator will range from about 700 lbs to 3300 lbs. The duration of the thrust is momentary to a few minutes depending on field strengths. The thrust bearing could be located at either end of the shaft and it must accommodate thrust in either direction. The thrust is not significant; the standard bearings from a major bearing manufacturer can be used. New bearings do not have to be designed.

Depending on the design of the Start-up Drive, some of the bearings associated with the turbine, especially the thrust bearing, may be reused or modified. In some cases an entirely new thrust bearing must be installed for condenser operation; this could mean that a stub shaft would have to be added to the shaft line.

The generator shaft grounding system must be used for condenser operation. Typically this is located between the Unit's turbine-end bearing and the turbine generator coupling; in this case no changes are necessary. This shaft grounding system will require regular maintenance.

Lubrication

Most turbine generators use the same bearing lubrication system for the turbine, generator, rotating exciter, and back-up oil for the seal oil system. With the turbine rotors and their bearings removed, the lubrication system will have to be evaluated for flow requirements. Some turbine bearing lube oil lines may need to be blanked.

The generator bearing oil system generally will not require changes. If the generator was originally equipped with a bearing oil-lift system, that should be maintained.

With less heating in the lube oil system, raw water flow to the bearing oil coolers may need to be reduced.

Depending on the design of the Start-up Drive System, it may be lubricated via the Unit's lubrication system. These changes will be specific to the plant layout and the Start-up Drive.

5.4 Mechanical Issues and Other Concerns

1. The original turbine generator shaft system was undoubtedly aligned and balanced for operation at rated speed. Hopefully the moment of inertias and torsional frequencies of the existing shaft line are known. Anytime a turbine generator shaft line element is removed, changed, or added, a dynamic analysis should be performed to make sure the torsional frequencies of the new shaft line is safely away from the system frequencies (i.e., 60 Hz and 120 Hz). We have to keep in mind that removing one or more of the shaft elements or adding an additional element (stub shaft, Start-up Drive) could have an impact on the dynamic forces on the foundation and result in shaft vibration. The turbines may have to stay in place to keep the foundation damped. The OEM will be helpful here. It would seem that a synchronous generator, not connected to a turbine, might spin free of vibration; do not underestimate the need for a torsional and a lateral evaluation.
2. Another area of concern is the plant or site location. Is the subject generator at an indoor location where other units are still in service, an indoor location where the plant is fully shut down; an outdoor location with other units still in service; or an outdoor location that is completely shut down? Is it a manned or unmanned location? Will the plant be heated in the winter? The condenser and excitation will be warmed by being in service, but some of the auxiliary equipment may need attention. When the condenser is out of service will a cold or hot ambient environment be an issue? Some auxiliary systems may require environmental protection such as heat tracing of cooling water and lubricating oil lines.
3. In general, 2 pole converted generators rated 100 MVA and above may require a turning gear assembly if the condenser is going to be out of service for extended periods of time. On most generators the turning gear assembly is on the turbine shaft at the turbine generator coupling. Other units have the turning gear assembly at the far end of the turbine shaft near the front standard. In either case, if the turning gear is needed, the assembly will have to be relocated. If it has to be replaced consider modifying the Unit for a higher turning gear speed, ~100 rpm; see Section 9 on accelerating the condenser. This could be a significant cost. The OEM should be consulted here. As a condenser, the unit should be on-line most of the time.

If a long down time is expected, typically more than 3 weeks, and a turning gear assembly is not available, the rotor shaft should be oriented so that the poles are at the 12:00 and 6:00 positions, which is the stiffest orientation of the shaft. After a defined time, the rotor can be rotated 180 degrees to reposition the two poles. A dial indicator riding on the turbine coupling can be used to determine if the shaft is bowed. Of course, manpower has to be available to do this.

4. The plant's fire protection system should remain in service. Fire protection can be down sized to cover just the condenser and the associated auxiliaries. The redesign will be very site specific.
5. Will the Utility to which the condenser is interconnected want remote control of the condenser for start-up, voltage control, and shutdown? This will add significantly to the cost. Primarily, this is due to the additional equipment, controls, and protection.
6. Keep in mind that the condenser is drawing power from the system. This is an operating cost. The Owner will have to discuss the accounting for this cost with the Transmission Co. Or, if an Operator is contracted separately, this cost will need to be correctly quantified, so as to represent accurately the cost of the contract. This is outside the Scope of this document.

6
THE EXCITATION SYSTEM

Here is where some equipment changes might be required.

Almost any excitation system can be used for condenser operation: 1) a rotating DC commutator exciter, either direct driven or gear driven; 2) a rotating alternator-rectifier with stationary rectifiers, 3) a rotating alternator-rectifier with rotating rectifiers (the brushless exciter) or, 4) a transformer potential source static system. These are the usual type of exciter systems installed for synchronous generator operation; they are all convertible to operation in support of a SC. However each excitation system will have unique considerations depending on the Start-up Drive System. See Section 8.2.

Given the advanced age of some generators that are candidates to be converted to synchronous condenser operation, a new transformer fed potential source static excitation system with a modern voltage regulator should be considered to replace the older rotating exciters. The cost of this new excitation equipment may be in the range of $1M+.

6.1 The Exciter

If the excitation is a brushless system, the permanent magnet generator (PMG) may need to be replaced with an AC source to power the voltage regulator. If the excitation is transformer fed potential source static system, the excitation transformer has to be fed from a plant auxiliary rather than the generator terminals. The DC bus power arrangement of the excitation system will generally not require changes. The generator field collector rings (slip-rings), carbon brushes, and DC leads will be the same.

6.2 The Voltage Regulator

The Voltage Regulator can often be reused, even if it is an old one. However, over and under excitation limiters will be required for condenser operation. For older excitation systems, one might want to consider the use of a digital Voltage Regulator.

6.3 Control of Field Current

The Transmission Operator sets a Grid voltage set point which the condenser's Voltage Regulator maintains. The Voltage Regulator's various alarm, limiter, and protection functions and set points will have to be reviewed for condenser operation. Once the condenser is synchronized to the System the Voltage Regulator operates the same as it does for a synchronous generator.

6.4 Collector Ring Brushes

The carbon brush current density loading may have to be evaluated for condenser operation. For generator operation the brush current density is about 50 amps per square inch. If the condenser is expected to operate at or near full lagging (over excited) capability, brush operation should not be an issue. However, if the condenser is expected to operate most of the time at leading (under excited) capacity the brush current density must be evaluated. Perhaps a brush or two may need to be removed to keep the brush current density at rated conditions; otherwise brush wear could increase or the collector ring could glaze over and impede current flow. Time in place testing will define this brush operating condition. The manufacturer and grade of the carbon brush used for generator operation should remain the same for condenser operation.

7
THE TURBINE

Of course, the turbine will not be used for condenser operation. As a minimum, the turbine must be decoupled from the generator rotor and may remain in place. If the turbine generator's turning gear assembly and thrust bearing is associated with the turbine; they will have to be moved to the condenser shaft. To make any further meaningful comments, details are needed for the turbine and the Start-up Drive arrangement.

See Section 5.4, item 1 for more information associated with the turbine.

8
THE CONDENSER START-UP DRIVE SYSTEMS

There are several methods used to bring the condenser rotor up to speed so it can be synchronized to the Grid. Of course, the turbine must be decoupled in all cases. Depending on the start-up method, the turbine may remain in place. The few conversions detailed in the Appendices describe basic examples of Start-up Drive System arrangements.

This document cannot offer detailed advice on the design of every Start-up Drive System. The configuration of the steam-turbine generator being converted; the plant layout; the auxiliaries, the type of excitation, and a plethora of other issues are needed in order to offer meaningful suggestions. Other circumstances such as a brushless exciter or cross compound units present challenges. On units with potential source static exciters, the exciter-end shaft of the generator may not be designed to withstand the starting torque required for some Start-up Drive System. A bearing oil-lift system may need to be added to the generator bearings to reduce the torque required during starting. In some cases, a high speed (~100 rpm) turning gear could be used to benefit the starting process.

Regardless of the starting means, the Start-up Drive must bring the condenser speed to about 10% over rated speed. The Start-up Drive torque is then removed from the condenser's rotor. The speed will decelerate back toward rated speed. During this short time interval the Voltage Regulator is put into service and the Synchronizing Relay monitors voltages, frequencies, and the phase angle for both the condenser terminals and the Grid. When these three parameters are within acceptable limits, the condenser is synchronized to the Grid.

For the majority of plant locations, the additional equipment required for conversion to condenser operation can be located on the turbine room floor. This includes the Start-up Drive (pony motor or Direct AFD Starting) and a new potential source static excitation system.

8.1 Start-up Drive Horsepower

The horsepower of the Start-up Drive is based primarily on the power needed to overcome the windage and friction losses of the generator at rated speed. The windage losses are generally provided by all generator manufacturers when a unit is purchased. As discussed in Section 6.2, a steam-turbine synchronous generator, energized by the Grid and spinning at rated speed, will draw only about 1% of the generators full load current with the turbine removed. This basically represents the windage and friction losses.

In Appendix A, AEP and the manufacturer estimated that the 38.4 MVA, 2 pole generator, would require only about 500 HP as a pony motor. A 1000 HP motor was used simply because that was available at AEP; a new motor did not need to be purchased. The full load current of the 38.4 MVA unit is about 1600 amps. With the generator's terminal voltage at 13,800 V and 16 amps (1% of 1600), the HP calculation would be 512 HP. For the 907 MVA unit in Section 6.2, the estimated start-up horsepower would be 12,000. This is a good estimating method to size the start-up horsepower requirements.

8.2 Start-up Drives

8.2.1. Direct across-the-line starting or reduced voltage starting, like starting an induction motor, is not likely with a synchronous generator. The synchronous generator rotor is not designed to carry the heavy starting currents that would be induced from the stator onto the rotor forging at or near standstill. The forging will overheat and fail. (Ref. 2)

8.2.2. An induction motor (as a pony motor) may be coupled to the condenser shaft. An induction motor operates at a slip speed; this is a speed approximately 5% below the synchronous speed at 60 Hz. Even a 2-pole induction motor will have a slip speed too low to allow synchronizing the condenser to the Grid. With an AFD connected to the induction motor, speed can be controlled to just above synchronous speed. A gear box may be required depending on the motor's rated speed. A clutch may be required to de-couple the drive motor during operation of the condenser.

In Appendix A, The turbine was removed and replaced with a simple shaft; the shaft had journals and a thrust collar in the same location as the turbine shaft and used all of the existing turbine bearings. An induction motor, with rated speed of 3560 rpm was coupled to the new shaft. An AFD was used to operate the motor to a speed above 3600 rpm for synchronizing. After synchronizing to the Grid, the motor was de-energized from the AFD but remained connected to the shaft and simply ran free-wheeling at 3600 rpm.

8.2.3. A synchronous motor (as a pony motor) may be coupled to the condenser shaft. With a 3600 rpm synchronous motor, this may be driven at 60 Hz and possibly allow the condenser to be synchronized to the Grid. With an AFD, the motor speed can be controlled to just above synchronous speed. A gear box may be required depending on the motor's rated speed. A clutch may be required to de-couple the drive motor during operation of the condenser.

Keep in mind that a pony motor drive may be attached to the turbine-end or the exciter-end of the generator shaft. Check with the generator manufacturer to be sure the exciter-end shaft can accommodate the starting torque.

8.2.4. Several gas-turbine generator units have been converted to synchronous condenser operation. For gas-turbine generators, there are basically two starting methods to accelerate the unit's compressor and turbine to operating conditions required for generation. In Figure 8-1 below are two shaft lines, A and B. The older and smaller units generally use a motor (shaft A) to accelerate the Unit's shaft to rated speed while the newer and larger units use a method known as "static start," also called a Load Commutated Inverter (LCI) starting method. (Ref. 3) These are established methods of starting modern gas-turbine generators. The static start is the "Direct AFD Starting" method discussed here for condenser projects. The combustion turbine units will be the easiest to convert for condenser operation as far as start-up is concerned. Please note, in Figure 8-1 that not all of the equipment required for operation is shown and that the location of some of the shaft components may differ between units or manufacturers; these are simple sketches.

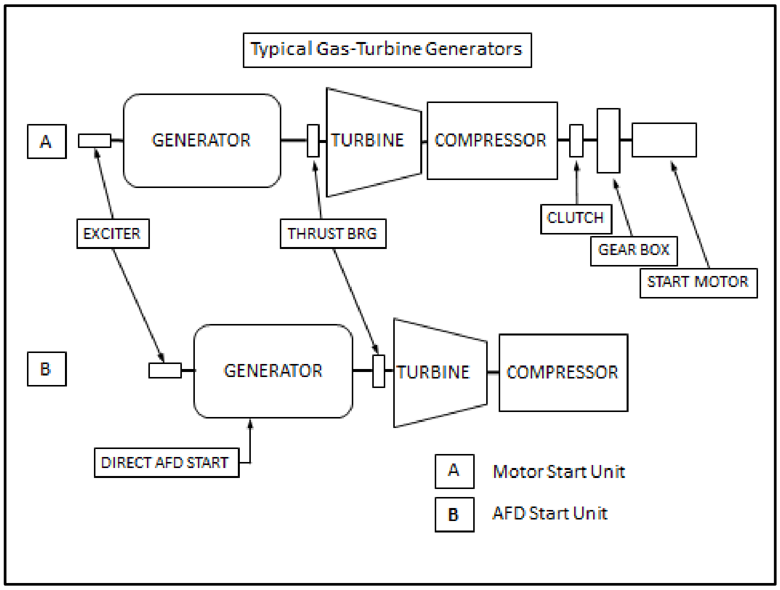

Figure 8-1
Typical Gas-Turbine Generators

Figure 8-2 shows some configurations for converting the gas-turbine units for operation as condensers.

To convert the motor starting unit (shaft A) to a condenser several options exist. Remove the turbine and compressor and move the clutch, gear box, and starting motor closer to the generator. Replace the turbine and compressor rotors with a new shaft, no blades of course, and retain the existing bearings. See Appendix A. Or, uncouple the generator from the turbine and use a Direct AFD Start.

To convert the Direct AFD Start unit (shaft B) to a condenser, simply uncouple or remove the turbine and compressor and use the existing Direct AFD Start to accelerate the unit. Speed control settings will need to be evaluated since the load of the turbine and compressor are not connected to the shaft. Here the generator is designed to accelerate as a synchronous motor and the supervising controls are designed to bring the unit to speed and synchronize to the Grid.

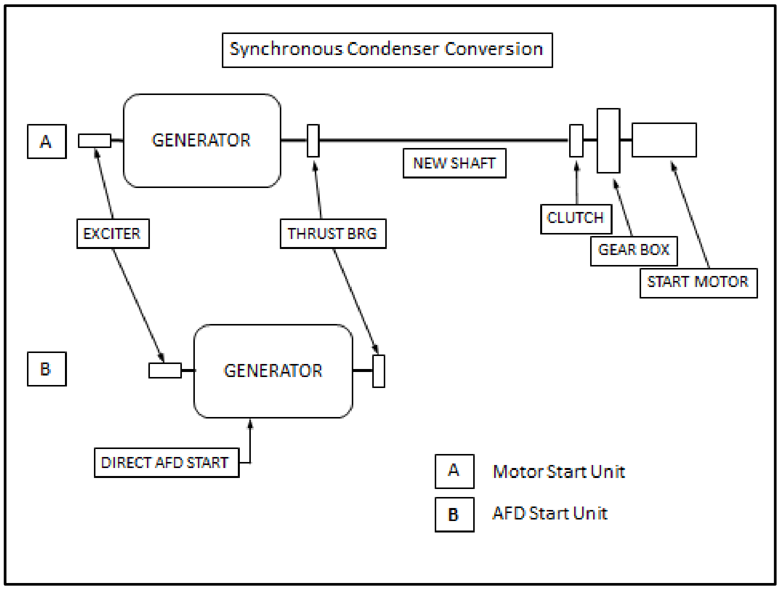

Figure 8-2
Gas-Turbine Generator Synchronous Condenser Conversions

8.2.5. In the past few years, the Direct AFD Starting method used on the gas-turbine units has been applied to the steam-turbine synchronous generator's stator winding and used to bring the unit to synchronizing speed by accelerating it as a synchronous motor. The use of Direct AFD Starting has very promising possibilities for many of the future conversion projects. Keep in mind that a steam-turbine generator is not designed to start as a synchronous motor; it is designed to be driven with a turbine. This starting method should be discussed with the generator manufacturer.

If the generator's rated voltage (terminal voltage) is relatively low, e.g., 6,900 volt or less, the AFD could possibly be connected directly to the stator winding. However, most units that are going to provide reasonable reactive support to the Grid are rated in 100's of MVA and will have rated voltages of 13,800 V or higher. Therefore, it is necessary to pass the output of the AFD to the low voltage side of a dedicated "AFD starting transformer" or an existing generator bus-connected plant auxiliary transformer so that the AFD output voltage is equal to the condenser terminal voltage.

In the Direct AFD Start system, such as that shown in Figure 8-3, the AFD drive, powered typically from a medium voltage power source such as a 4160 V or 3300 V switchgear bus, provides adjustable frequency power to the synchronous condenser's stator winding. The condenser's field winding is excited by sufficient exciter field current to establish a suitable level of rotor magnetic flux. The current from the AFD produces stator flux which interacts with the rotor magnetic flux in the condenser producing an accelerating torque. In this starting scheme the rotor is pulled into magnetic center as soon as the stator field is established; there is no thrust developed during start-up. As the output frequency of the AFD is increased, the condenser speed will accelerate from standstill (or turning gear speed) to a synchronizing speed. This process could take as long as 20 minutes depending on the size of the condenser.

As Figure 8-3 shows, it is possible to use one AFD to start more than one synchronous condenser. This arrangement is similar to that used for the static start arrangements of multiple gas-turbine generators at the same site, especially those of multi-shaft combined cycle gas-turbine generators.

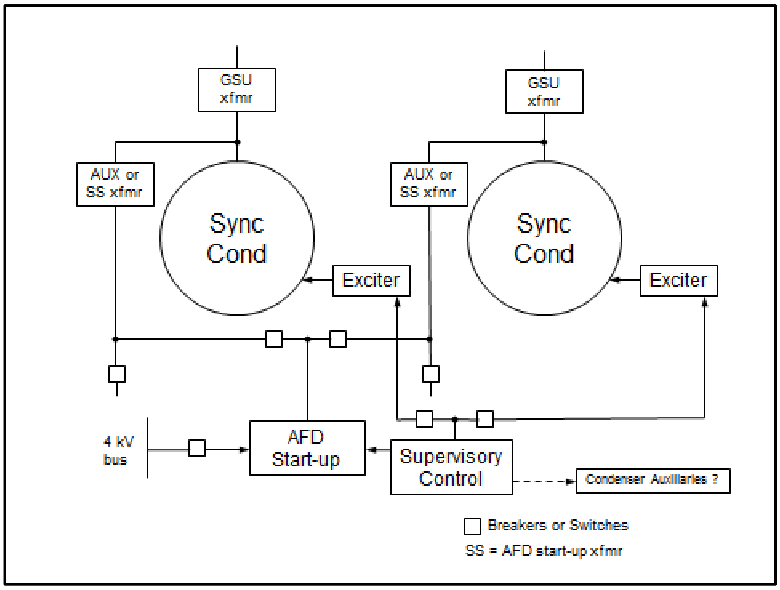

Figure 8-3
Conceptual Arrangement, Static Start for a Two Unit Location

The operating concerns for the Direct AFD Starting method is overheating of the rotor (winding, forging, wedges, or retaining rings) or slipping poles while increasing speed. With Direct AFD Starting, a start-up Supervisory Control System is needed to regulate the AFD (controlling the stator field) and the exciter output (controlling the rotor field) to provide a smooth start-up to prevent these operating concerns. Also, in perhaps some older units, the design of the generator rotor (wedge material, damper winding design or material) may be an issue since the generator's rotor will be operated as a synchronous motor rotor. If, for some reason, the generator rotor needs to be rewound, any modifications to enhance Direct AFD Starting can be easily made.

For older generating units, with aging control circuits, serious consideration should be given to expanding the function of the Supervisory Control System to monitor and operate all of the Condenser Auxiliary systems (cooling water, lubrication, hydrogen, etc.) as well as any other balance of plant systems required for the operation of the synchronous condenser. This is represented by the dashed line in Figure 8-3. These controls should be able to handle start-up acceleration, synchronization, operation, and shutdown (routine and emergency) of the condenser. In addition, an overall Supervisory Control System could be used to island the condenser and its auxiliaries from the other balance of plant equipment. For plants that will not be returned to generation operation, it will allow dismantling of that equipment while leaving the condenser controls centralized and intact.

8.3 Generator-Exciter Configuration

The generator-exciter configuration will have a substantial impact on the use of a Direct AFD Drive.

The Direct AFD Drive (8.2.5) start-up system must be capable of exciting the synchronous condenser's field winding to some reasonable flux level while at standstill or on turning gear. Therefore, most rotating exciters (alternator and brushless) and the generator bus-connected transformer potential source static exciters will not be suitable for this start-up method because they do not produce field current when the unit is at standstill or on turning gear. For Direct AFD Drive starting, rotating exciters generally will have to be replaced. For brushless exciters this means that not only a new potential source static excitation system is required but also a stub shaft with collector rings and a carbon brush holder assembly. When designing the stub shaft, consider incorporating the thrust bearing and the turning gear assembly. Potential source static exciters will need to be connected to a source energized from an auxiliary switchgear bus, a motor/generator set, or a suitable alternative supply.

The use of a pony motor (8.2.2 and 8.2.3) as the Start-Up Drive can be used on any of the generator-exciter configurations without major modification to the excitation system.

For gas-turbine generators (8.2.4), the generator-exciter configuration is also not an issue for the excitation system.

Given the advanced age of some generators that are candidates to be converted to synchronous condenser operation, a new transformer fed potential source static excitation system with a modern voltage regulator should be considered to replace the older rotating exciters. The cost of this new excitation equipment may be in the range of $1M+.

9

CONTROLS, PROTECTION, AND SYNCHRONIZING

There are some minor changes needed here. As stated above, the condenser maximum stator current is about 70% of full load current. The field current will likely operate over the full range of reactive capability. A review of the protection, by the plant relay engineer, is necessary for operation as a condenser. Here are some issues to consider:

Metering

- Due to current flowing into the stator.
- For accurate accounting of energy costs.

Relaying

- Under and over frequency - due to operating at low speeds for long times during starting or the use of an adjustable frequency drive.
- Consider the impact of frequency on the generator step-up and auxiliary transformers.
- Synchronizing - this is dependent on the Start-up Drive System type.
- Reverse Power - due to current flowing into the stator.
- Field protection - due to the fact that the field may be operating at or near full load much of the time; review alarms, limiters, and protection settings.
- Frequent operation at either extreme of reactive load may effect relaying and protection practices.

10

HIGH VOLTAGE BUSHINGS, LEADS AND TRANSFORMERS

As stated for the generator operating as a condenser, all of the voltage issues will be the same since the condenser operates at rated terminal voltage and the maximum stator current will be about 70% of full load current. The high voltage bushings, leads, and generator step-up and auxiliary transformers should not require any changes. Again, due to the lower stator current, these components may see less heating.

The unit's auxiliary transformer loading has to be evaluated since the overall plant auxiliary load is significantly less when operating as a condenser.

11

CONVERSION EXPERIENCE

11.1 Utility Conversions

The Appendix contains summary accounts of some conversions; unfortunately many of these accounts are not very detailed.

There are many studies on System reactive power compensation using capacitors, or a static var compensator system, as compared to a synchronous condenser. The vast majority of those comparisons are for “new installations”. The economic evaluation for a new installation for a synchronous condenser, capacitors, or the static var equipment is not comparable to conversion of an existing synchronous generator. New systems require land acquisition, foundations, buildings, utilities, all new equipment, significant high voltage switchgear, transformers, and right-of-way to the transmission line, and much more.

On the other hand, converting a retired generator for operation as a condenser is an entirely different evaluation, where almost 90% of the equipment required already exists and has been paid for, Utility interconnection is established, and ancillary equipment is in place. Thus, stranded assets are being put to productive use. Attempting to compare an existing synchronous generator conversion with a new installation of capacitors or static var equipment is not only a biased evaluation; it will not yield comparable results.

There is sparse generator conversion experience in the public domain. In early 2013, EPRI conducted a member survey called “Converting a Generator into a Synchronous Condenser Operation,” (Ref 4) There were about 20 respondents, none currently owned or operated a converted synchronous generator as a condenser. Three respondents had plans to do a conversion and seven said they were looking with interest. A review of the IEEE Member Digital Library and was disappointed; using several key words and phrases, not a single article on the topic of generator to condenser conversion came up.

11.2 Known Conversion Projects

Listed below are some of the known conversion projects, showing the year of installation, and years of operation, where available. Where conversion information was made available, a summary is provided in the Appendix with the same letter designation. Unfortunately, there is no information on a few of these projects.

A. AEP - Trash Burning Power Plant Conversion, 3×35 MVA, by AEP, 1999 (2 yrs)

B. AEP - Philo Unit 6 Conversion, 1×156 MVA, by AEP 1980 (not completed)

C. FirstEnergy - Eastlake Units 4&5, 2×240 MW, by GE/Sargent Lundy, GE Static Start, 2012, two other Units are scheduled for conversion in 2015 and an additional Unit in 2017

D. Exelon - Zion Nuclear plant, 2×1100 MVA, 1998, (11 yrs)

E. RWE Power AG, Germany - Biblis A Nuclear, 1×1200 MW, Siemens, Direct AFD starting, 2011

F. AES - Huntington Beach 3 & 4, 225 MW, 2013

G. PSE&G - running jet engines with air-cooled generators (EM) in SC mode
H. Xcel - Cherokee 2, GE Static Start, 106 MW Unit retired in 2011
I. AES - at the time belonged to NYSEG, then purchased by AES, in Binghamton, NY, Westinghouse, ~ 46 MVA
J. FPL - Turkey Point 2, GE Static Start, 400 MW

12
INTERCONNECTION CONSIDERATIONS

The synchronous condenser has to be modeled to verify that there are no unfavorable resonant conditions that would affect System stability at the interconnection point. The synchronous condenser resistances, reactances, and time constants must be provided for a stability study. The condenser's inertia constant will be much less than that of the turbine-generator shaft line since the turbine shaft is not connected. Most vendors provide the inertia constant of the generator alone. The Owner of the converted condenser must investigate the NERC regulations and review local interconnection requirements. Because a definite Utility, Unit, and location are not identified, this document cannot offer specific comments here; these are site specific issues.

13

NERC AND REGULATORY ISSUES

Even for a synchronous condenser, the NERC requirements and standards are legion and therefore are not included in the Scope of this document. Nevertheless, below are three NERC procedures that apply to synchronous condensers. It seems that if the synchronous condenser is rated greater than 20 MVA, the NERC verification and reporting requirements are the same as a synchronous generator. NERC MOD-026, which addresses machine modeling, does not yet include synchronous condensers.

For more information, and the details, go to the NERC web site. <nerc.com>

Check with your NERC Coordinator for specifics in your service area.

NERC MOD-025-2

1. Title: Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

2. Number: MOD-025-2

3. Purpose: To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

4. Applicability:

4.1. Functional entities

4.1.1. Generator Owner

4.1.2. Transmission Owner that owns synchronous condenser(s)

4.2. Facilities: For the purpose of this standard, the term, “applicable Facility” shall mean any one of the following:

4.2.1. Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.2. Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.3. Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

Note 4: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.

NERC PRC-019-1

1. Title: Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. Number: PRC-019-1

3. Purpose: To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. Applicability:

4.1. Functional Entities

4.1.1. Generator Owner

4.1.2. Transmission Owner that owns synchronous condenser(s)

NERC VAR-002-WECC-1

1. Title: Automatic Voltage Regulators (AVR)

2. Number: VAR-002-WECC-1

3. Purpose: To ensure that Automatic Voltage Regulators on synchronous generators and condensers shall be kept in service and controlling voltage.

4. Applicability:

4.1. Generator Operators

4.2. Transmission Operators that operate synchronous condensers

4.3. This VAR-002-WECC-1 Standard only applies to synchronous generators and synchronous condensers that are connected to the Bulk Electric System.

14

COST OF CONVERSION

It is very difficult to get cost figures for a synchronous condenser conversion without identifying a specific Unit. Capital costs can't be estimated not knowing what needs to be purchased or modified. The same goes for operation and maintenance costs. The cost of losses isn't known until the equipment is known. Once a specific Unit is identified, the Owner can then begin the engineering; determine what is required; and approach the OEM and Vendors for estimates of cost.

It is fortunate that a study (Ref 5), comparing the Synchronous Condenser vs Static var Compensation (SVC) vs Static Synchronous Compensator STATCOM was located. Although a comparison of reactive power compensation devices is not actually within the Scope of this document, the study by Teshmont Consulting LP of Winnipeg, Alberta, is a very inclusive comparison of the three reactive power compensation devices. The study, done in 2005, has cost figures which, for this specific project, favor the synchronous condenser. The costs in the Teshmont study will have increased for 2013 but the ratio of costs should be essentially the same. For general information, the two tables below are from this study.

Table 14-1 identifies the main operating characteristics of the three systems, their pros and cons are compared to each other. It is sadly noted that maintenance is not covered in this table. It would seem there could be large variations in the amount of maintenance required for the three systems.

Table 14-1
Characteristic of Var Support Technologies

Functional Characteristic	Synchronous Condenser	SVC	STATCOM
Type	Rotating Machine	Controlled Impedance	Synchronous Voltage source
Response to transient events	Slow (response time in the order of 1 second)	Fast (response time in the order of 70 ms)	Fast (response time in the order of 50 ms)
Continuously variable reactive output	Yes	Yes	Yes
Robust Response to severe voltage dips	Yes	No	No
Robust Response to moderate voltage dips	Yes	Yes	Yes
Inherent transient overload rating	2 times	No	No
Independent phase control	None	None	Yes (of limited benefit in utility applications)

Table 14-1 (continued)
Characteristic of Var Support Technologies

Functional Characteristic	Synchronous Condenser	SVC	STATCOM
Discretely controlled output	Slow	Fast	Fast
Harmonic Generation and Filtering	No Harmonics	Yes (Low order odd harmonics are characteristic harmonics)	Yes (Several distinctly different technologies all with different harmonics)
Output dependent on bus voltage	Independent of bus voltage	Decreases with square of voltage	Decrease linearly with voltage
Efficiency	Lower	98-99%	98-99%
Foot print size	Medium	Large	Medium
Ease of installation and commissioning	Simple	Complex	Complex
Cooling	Direct air/H_2 cooled or Liquid cooled	Liquid cooled	Liquid cooled
Losses	Relatively high at all output levels	Low at zero output and Medium at rated output	Low at zero output and high at rated output
Inertia adds to system stability	Yes	No	No
Cost	Low	Medium	High
Audible noise	Outdoor air coolers	Outdoor air coolers. Outdoor reactors with fundamental and low order harmonic noise.	Outdoor air coolers. Outdoor reactors with fundamental and higher order harmonic noise.
Complexity of Impact studies	Easy	Complex including harmonic studies and control interaction studies.	Complex including harmonic studies and control interaction studies.
Expected Ease of Regulatory Approval	Easy	More difficult.	More difficult.
Construction Schedule	Quick (<1 year)	18-20 months	18-20 months
Ease of future Expansion	Easy	Easy	Easy

This was a two Stage Project evaluation. Stage 1 required 150 Mvar in 2006 and Stage 2 was to have 300 Mvar in 2012. Table 14-2 compares costs for the three options. It is important to keep in mind that the Teshmont study was for a completely new synchronous condenser installation, not the conversion of an existing generator.

For a generator to condenser conversion project, several of the items in Table 14-2 will not be required. For Stage 1, in the Condenser column, the struck thru items are not required. However, there will be some costs of the conversion that are not itemized in Table 14-2. Especially missing is the Start-up Drive System (~$1M); costs associated with the thrust bearing

(~$5k); and, if needed a new potential source static excitation system ($1M). These estimates were added to the three rows (in bold) to get a rough estimate for the total conversion cost.

Now, trying to compare a synchronous generator conversion to the Teshmont study is not an apples-to-apples comparison, but it gives some idea of the costs involved. The conversion can be significantly less that a new synchronous condenser installation.

Table 14-2
Comparative Costs of Reactive Power Device Options (Costs are in $Thousands)

	Stage 1 (Year 2006)			**Stage 2 (Year 2012)**		
	Condenser	**SVC**	**STATCO**	**Condenser**	**SVC**	**STATCOM**
Synchronous Condensers	~~$4,584~~	--	--	$4,584	--	--
Exciter	Included	--	--	included	--	--
Incoming line cubicles	Included	included	included	included	included	included
VC/STATCOM		$11,830	$11,333		5850	$11,333
Coolers	~~$870~~	Included	included	$870	included	included
Spare parts	~~$29~~	$250	$250	$29		
Supervision 30 days	**$48**	included	included	$48	included	included
Installation	**$200**	included	included	$200	included	included
13.8 kV Switchgear and Starting Reactors	~~$1,835~~	included	included	$1127	included	included
13.8 kV Bus	~~$354~~	$354	$354	$52	$52	$52
Transformer Cost (increment)	~~$480~~	$480	$480	--	--	--
Synchronous Condenser Building	~~$1,969~~	0	0	$150	0	0
SVC Building		included	included		included	included
Contingency	**$573**	1,208	1158	573	585	1133
Total Cost in Each Stage	$10,942	$14,122	$13,575	$7,633	$6,487	$12,519
NPV of Stage 2				$4,551	$3,868	$7,464
NPV Grand Total Stages 1&2				$15,492	$17,990	$21,039
Conver. Start-up Drive	**1,000**			$4,551	$3,868	$3,868
Conver. Thrust Bearing	**50**			$4,551	$3,868	$3,868
Conver. New Exciter ???	**1,000**					
Conver. Estimate Total	**$2,871**					

http://www.velco.com/Projects/NRP/Documents/Northwest/Reactivity%20Study%20Report.pdf

Vermont Electric Power Company, Granite Reactive Power Device (January 2005)

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A

SYNCHRONOUS CONDENSER CONVERSION PROJECT

Abstract

In 1999, anticipating a long hot summer with near peak loads, American Electric Power (AEP) converted three retired 33 MW synchronous generators for operation as synchronous condensers. The City of Columbus' "Waste to Energy Facility" (WEF) went into service in 1984 and was shut down in 1995. This plant had three 38.4 MVA, 13.8 kV, 0.85 pf, 3600 rpm, and air-cooled units. The units were connected to a 69 kV system and then AEP's system at 138 kV. In 1999 the turbine generators were leased to AEP's affiliate Columbus Southern Power Co. from the plant Owners. These condensers would help support the City's 69 kV and AEP's 138 kV transmission systems and provide increased transfer capacity to AEP's high voltage transmission system.

AEP's Regional Service Organization (RSO) employees performed the physical work at the plant. The plant's boilers, fuel handling system, and ash handling system were not affected by the conversion. Only the turbine, generator, excitation system, their auxiliaries (lubrication and cooling water), the 13,800 volt generator output bus and generator step-up transformer were part of the conversion. An adjustable frequency power supply, a bladeless turbine shaft, three 50-year-old motors, and good engineering made this conversion possible. The basic procedure was:

1. Remove the turbine's rotor and replace it with a shaft that has a coupling for the generator and an outboard end coupling for a motor to drive the generator to synchronous speed. The shaft will be coupled to the generator and utilize the existing turbine bearings, and lubrication system including the thrust bearing.
2. Attach an AC induction motor to the outboard end of the new shaft. Drive the generator rotor to rated speed using an adjustable frequency power supply for the induction motor.
3. Near rated speed, energize the generator's excitation system providing a field to the generator.
4. Manually parallel the generator to the system as a synchronous condenser.
5. Place the voltage regulator in service with the regulator in Automatic to hold a specified 69 kV voltage.
6. Open the feed breakers to the drive motor and the adjustable frequency power supply. The motor's rotor will then spin freely, driven at 3600 rpm while the synchronous condenser is on line.

Introduction

The Waste to Energy Facility

The plant yard is 69 kV and is connected to the AEP System at 138 kV. Anticipating a re-powering of the facility, the Owners maintained the facility in excellent condition during the shutdown period.

The design basis for the conversion of the three synchronous condensers was the ability to operate 24 hours a day seven days a week as an unattended facility. However, the units would be started and shutdown manually. Traditional and commercially accepted electric power plant protective relaying was used for automatic monitoring, protection, and shut down in the event of equipment failure. There was no remote control or supervisory controls. AEP's Columbus-based engineering organization provided operation and maintenance support.

The Challenges

Of course, there were many challenges associated with this conversion to synchronous condenser operation. We generally think of a condenser as a stand-alone single shaft unit that is started across-the-line. There was the need to get to rated speed, the need to couple a drive to the generator rotor, the need for a thrust bearing, applying excitation, synchronizing, protective relaying, operational limits, and instrumentation.

There were also several issues associated with the ancillary equipment at the plant. The synchronous condenser needed cooling water to the bearing lubrication oil system and the generator cooling air system. The lubrication oil system would have to be modified because the turbine would be removed. The cooling water system would also need modification since the turbine's condenser and the boiler were not in service. The plant battery also needed inspection and testing.

One of the design basis goals was to be able to return the units to conventional power generating operation. Therefore, no major changes could be made to the existing equipment, controls, protection, or foundations.

Getting the generator rotor to rated speed was the major challenge of this conversion project. AEP initially had three ideas.

1st – Review the generator rotor design and construction with the manufacturer. If the unit had a good robust, dedicated, copper damper winding we could uncouple the turbine, startup the lubrication system; start the turning gear motor; and direct-across-the-line-start the generator like an induction motor.

2nd – Remove the turbine rotor and couple a 3600 rpm synchronous motor to the generator rotor and bring the shaft to rated speed.

3rd – Use an induction motor, powered with an adjustable speed drive (ASD), to bring the shaft to synchronous speed.

Needless to say, the first suggestion was dropped after talking with the generator manufacturer. They assured us that the generator rotor would not survive a direct-across-the-line start. Finding an existing synchronous motor for this project would be difficult. We needed three 3600 rpm, high inertia synchronous motors rated between 500 HP and 1000 HP. We did not have time to order new motors for the application. We turned our attention to the third idea, an induction motor driven with an ASD to bring the generator rotor to rated speed.

The Work Begins

The turbine and foundation drawings were reviewed. The complete turbine casing would have to be removed and a foundation attachment fabricated to mount a drive motor and couple it directly to the generator rotor. This would require a great deal of turbine disassembly and many hours of additional work impacting our schedule. Mounting the drive motor on top of the lower shell and using gears, clutches, belts, etc. was also considered; all were costly and time consuming.

A suggestion came from one of AEP's Staff mechanical engineers to remove the turbine rotor and replace it with a new shaft without blade roots. The shaft would have a generator coupling, bearing journals to match the existing bearings, a thrust runner to match the existing thrust bearing, and an extension through the turbine front standard with a coupling for a drive motor to be mounted on the turbine room floor.

We needed to review the existing plant equipment; do the work on the turbine; procure the new shaft; locate and install the drive motors; procure the ASD equipment; modify a high voltage bus for the ASD and drive motors; review the protective relaying and controls; and prepare an operating procedure. The RSO began work at the plant on May 17th. The RSO inspected and cleaned the lubrication oil and cooling water systems. They revised the lubricating oil system to accommodate the drive motor and modified the cooling water system to handle the reduced water flow. RSO electricians reviewed the electrical system changes required. Switchgear, protective relaying, instrumentation, controls, annunciation, and metering circuits all had to be inspected. They isolated one of the plant's 4 kV busses to accommodate the ASD and drive motors.

The Generator and Excitation

The synchronous generators were manufactured in 1978. The units are 38.4 MVA, 13.8 kV, 0.85 pf, and 3600 r/min with an air-cooled TEWAC enclosure. The units had PMG brushless exciters with an analogue voltage regulator.

The WEF plant personnel stored the generator and exciter enclosures in excellent condition. An AEP engineer performed a visual inspection of each generator. The stator winding and field winding were Meggered® and a Polarization Index was taken. The windings were not high potential tested and the rotors were not removed from the stators for a visual inspection. The generator air coolers were removed and cleaned.

The PMG brushless exciter was in good shape also. The voltage regulator was not equipped with over or under excited limiters. Since we were operating as a synchronous condenser we felt a need for this limiter protection. We contacted the generator manufacturer and discussed these voltage regulators. Limiter circuits were not available for these obsolete VR 41 regulators. We purchased a new digital voltage regulator for each unit. At the completion of the project, these regulators were used to replace old regulators at three AEP hydro units.

The Drive Motors

The generator manufacturer and AEP estimated that 500 HP was required to drive the generator rotor to rated speed. This horsepower requirement is based primarily on the known windage losses. AEP located three boiler feed pump motors at a retired AEP Plant. These 1000 HP, 3560 r/min, 2200 volt, three phase induction motors were manufactured in 1944.

All three motors were sent to the AEP repair facility in Charleston, WV. for evaluation. The motors had a shaft driven oil supply system, which was removed. The shaft driven pump was seen as a liability to operation during the slow run up and when the motor was being driven by the synchronous condenser. The bearing lubrication was fed from the turbine generator lubrication oil system.

The motor's design rotation was opposite to that of the turbine generator. The motor's rotor fans were only slightly directional, almost radial; the bearings were rotated to accommodate an oil relief groove in the Babbitt, and the motors were run in the reverse direction for one hour without high bearing temperatures.

A flexible coupling was used to connect the drive motor to the new shaft. Starting time was 15 to 20 minutes. Because the drive motors would be running at slow speed during the starting period, an auxiliary cooling fan was mounted on each motor's air exhaust opening to provide additional cooling. These fans were operated on/off with aux contacts in the motor breakers.

Because of concerns regarding adequate lubrication of the motor bearings, the 4 r/min turning gear operation of the turbine-generator shaft was limited to the minimum time possible.

The Turbine and New Shaft

The new shaft was manufactured from a solid shaft approximately eight inches in diameter and 19 feet in length. The shaft size was based on the largest journal diameter. The shaft was engineered to replace the existing turbine rotor; this allowed use of the existing turbine bearings and provided a means to couple the drive motor to the generator. The shaft design utilized the existing turbine thrust bearing to restrain axial movement of the generator rotor. The drive shaft was extended through the front standard of the turbine to allow for coupling to the 1000 HP drive motor. After the new shaft was installed the turbine upper shell was reinstalled.

The new shaft design torques, frequencies, bearing loading, thermal growth of the generator, and coupling alignment were all evaluated for the new shaft. The first critical on the new shaft segment between the two turbine sleeve bearings was similar to the original turbine shaft. The first critical on the segment of turbine shaft overhanging the front standard was estimated to occur above 3600 r/min.

Lubrication

Each plant turbine generator had a completely independent lubrication oil system. The lubricating oil system was reused in its entirety with only a few modifications. The existing #1 and #2 turbine sleeve bearings were modified to reduce the chance of oil whip that could occur with the lightly loaded new shaft. The oil feed lines to the drive motor bearings were connected to an existing supply tap located on the turbine generator oil supply tank. The drain from the drive motor bearings was piped to the #1 bearing drain.

Cooling Water

Three temporary screen house pumps were installed to supply water to the existing circulating water header. The existing circulating water pumps were not used. Each synchronous condenser unit required a total of 700 gpm of cooling water to supply the generator air coolers and the lubricating oil heat exchangers. The temporary pumps kept the circulating water header flooded. The circulating water header was used as a reservoir for the existing Cooler Pumps, located in the plant. As backup for the temporary pumps, an existing municipal water connection could supply water to the discharge side of the Cooler Pumps.

The ASD Bus

We were fortunate that this three unit plant had a small 4 kV Tie Bus section capable of feeding the three unit busses. This Tie Bus could be easily isolated to establish an ASD bus for the ASD and the three drive motors. No additional 4 kV breakers were needed for this project. Figure A-1 shows the ASD bus arrangement. During normal synchronous condenser operation all five of the breakers on the ASD bus are open.

The Adjustable Speed Drive

The adjustable speed drive was leased from Robicon. The ASD was Robicon's Perfect Harmony, rated 1000 HP, 4 kV, and 150 amps. The ASD power circuit configuration is series - pulse width modulated (PWM). This means that several low voltage PWM drives are connected in series to achieve the medium voltage rating. The ASD has a 1250 kVA integral input transformer. The transformer has 1 three-phase primary winding and 18 three-phase secondary windings. Each secondary winding (3-phase, 600 volts) feeds a low voltage PWM drive. Six drives are connected in series to complete each phase of the drive. The ASD input power is 4160 volts, 3-phase, 60 Hz; the ASD output power is 0 to 4160 volts, at 0 to 120 Hz.

A 1000 kVA step down transformer was purchased for the 4160 volt ASD output to accommodate the 2200 volt rated terminal voltage of the startup motor. This transformer was designed to operate with a frequency range of 0 to 66 Hz at a constant 140 amperes current and a constant volts per hertz ratio.

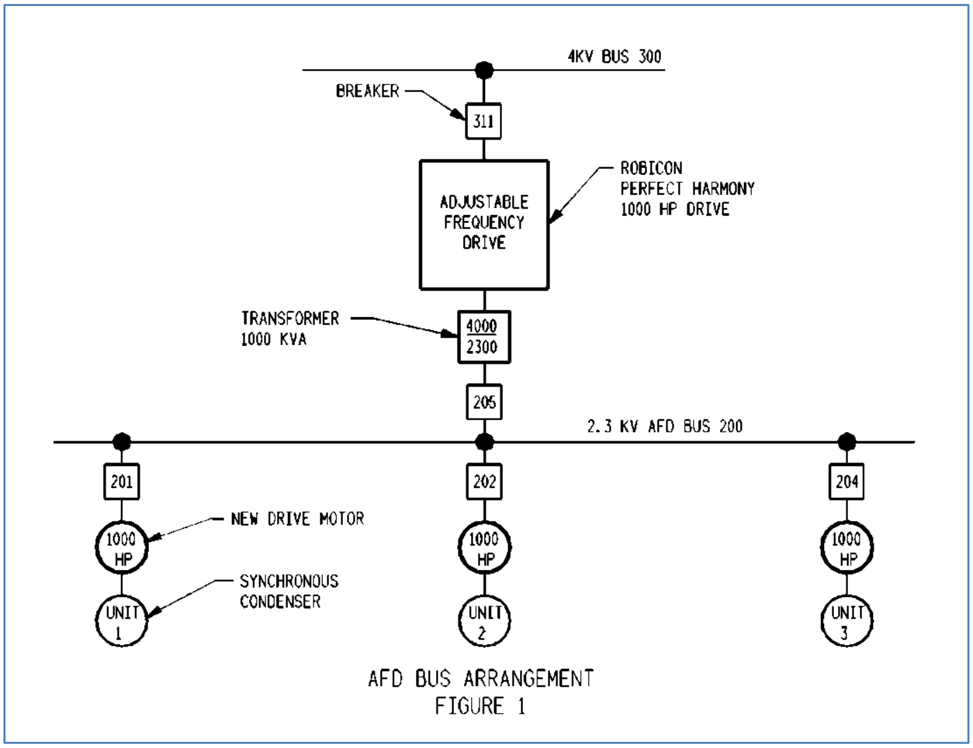

Figure A-1
ASD Bus Arrangement

Operation

The operation of the condensers more than exceeded their desired goal. During the national heat wave the last half of July 1999, the condensers basically "paid" for the conversion costs by maintaining the Plant's 69 kV and AEP's 138 kV voltage levels during record loads. The three synchronous condensers operated without significant issues throughout the summers of 1999 and 2000.

Conclusion

This was truly a win-win-win project for all parties involved, the plant Owners and AEP. Cooperation among the parties was 110% throughout the project. The conversion project was on schedule and within the budget proposed. The project showed that innovative engineering and cooperation among the affected parties can turn otherwise unproductive, retired equipment into productive profitable use. Substantial revenue was earned because the condensers provided reactive support to the AEP 138 kV transmission system, allowing an increase in capacity. In 2001 a new 765 kV substation was installed on the north side of Columbus and the need for the condensers was mitigated.

After the lease agreement expired, the plant was formally retired. The turbine generators were sold to another party and removed from the plant. The Robicon ASDs were returned to Robicon. The drive motors were returned to an AEP plant.

B
CONVERSION OF PHILO UNIT 6

Back in about 1980, American Electric Power (AEP) began converting a retired synchronous generator for condenser operation. The condenser would support an industrial customer in the service area that planned to install a new arc furnace.

Philo Unit 6 was a 1956 vintage 156 MVA, indirect hydrogen cooled, 15kV, 3600 rpm unit. The Philo plant was taken out of service in 1975. Philo Unit 6 had a gear driven DC generator excitation system. The turbine, spinning the generator, would spin the DC generator exciter, through a speed reduction gear, to provide excitation to the field winding. The Voltage Regulator controlled the DC voltage.

The AEP mechanical shop personal removed the turbine and fabricated a stub shaft containing a thrust bearing with the appropriate lubrication. They inspected and cleaned the generator's auxiliary equipment that was needed for the conversion. Since the plant was out of service there was no building heating available and some of the auxiliary piping required heat tracing.

At that time, AEP owned a large mobile exciter. This was a complete, late 1970s, excitation system, trailer mounted, transformer fed, potential source, static excitation systems with a full Voltage Regulator containing all of the up-to-date alarm and limiter circuits. The mobile exciter trailer was lifted to the turbine room floor.

The Start-up Drive system was to use the mobile exciter for the DC power supply to drive the exciters DC generator as a DC motor to bring the generator rotor to rated speed through the gear box. The mobile exciter was also the excitation system for the condenser once it reached rated speed. After reaching rated speed the mobile exciter output was switched from the DC exciter to the collector rings of the field winding in order to synchronize the condenser to the System. The mobile exciter then remained in service as the voltage regulator for the condenser. The generators gear driven DC exciter just remained spinning.

The condenser was synchronized just a few times to the AEP system. The DC supply current through the DC motor was too high for the motor commutators, and we burned up a few of them. The WR^2 of the generator rotor was just too great. The gear drive was also a hindrance to a smooth start-up. AEP would have to purchase a larger DC drive motor.

As is often the case, circumstances changed. The owner of the arc furnace decided to not install a new furnace. The project was aborted.

C
EASTLAKE UNITS 4 & 5

FirstEnergy is converting 5 generating units for synchronous condenser operation. Their evaluation showed that the conversion of the units to synchronous condensers was a more economical, effective and expedient solution than the installation on new SVC's.

- Eastlake units 4 and 5, 2×240 MW, by GE/Sargent Lundy, GE Static Start, Direct AFD start-up drive, converted in 2013.
- Four additional FirstEnergy units are scheduled for conversion in 2015.

D
ZION NUCLEAR PLANT

Exelon – Zion Nuclear plant: SC is now decommissioned.

- Zion Plant retired from generation in 1997.
- Both Zion units went on-line as SC's in 1998.
- Generators were decoupled from turbine.
- A large induction motor and a torque converter/hydraulic clutch were used to accelerate rotor to 1800 rpm. The induction motor was connected to the exciter-end of exciter shaft.
- Voltage regulator used to push or pull vars (+/- 400 Mvars).
- The Motor/Torque converter skid moves between units for start-up needs.
- Additional lube oil system installed on each unit for start-up skid needs.
- Existing turbine lube oil system used for bearing oil, had to modify generator bearings for bearing lift oil.
- Added a thrust bearing.
- Normally run both through the summer and alternate taking one off for the winter.
- Our T&D people were pleased with the capabilities that the SC's give them.
- Was originally planned for 3 year service life but they operated until 2011.
- Westinghouse (now Siemens) did the conversion and engineering.

E

BIBLIS A NUCLEAR

The RWE Power AG, Germany had the 1200 MW Biblis A, a nuclear plant generator, converted to condenser operation by Siemens in 2011.

- The Direct AFD start-up method was used.

F

HUNTINGTON BEACH 3 & 4

Huntington Beach 3 & 4. These units were converted to condenser operation by Siemens.

- These are cross compound units.
- The turbines were uncoupled.
- The two generators were electrically tied together at low speed.
- A Starting motor (pony motor) was attached to one shaft.
- An adjustable frequency drive was used to accelerate the pony motor and both shafts to synchronizing speed.

G APPENDICES G THROUGH J

No information available on these projects.

Appendix G: PSE&G - running jet engines with air-cooled generators (EM) in SC mode.

Appendix H: Xcel - Cherokee 2, GE Static Start, 106 MW Unit retired in 2011.

Appendix I: AES - at the time belonged to NYSEG, then purchased by AES, in Binghamton, NY, Westinghouse, ~ 46 MVA.

Appendix J: FPL - Turkey Point 2, GE Static Start, 400 MW.

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Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com